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Depleted hydrocarbon reservoirs and CO2 injection wells –CO2 leakage assessment

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Original scientific paper

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Abstract

Migration risk assessment of the injected CO_2 is one of the first and indispensable steps in determining locations for the implementation of projects for carbon dioxide permanent disposal in depleted hydrocarbon reservoirs. Within the phase of potential storage characterization and assessment, it is necessary to conduct a quantitative risk assessment, based on dynamic reservoir models that predict the behaviour of the injected CO_2, which requires good knowledge of the reservoir conditions.

A preliminary risk assessment proposed in this paper can be used to identify risks of CO_2 leakage from the injection zone and through wells by quantifying hazard probability (likelihood) and severity, in order to establish a risk-mitigation plan and to engage prevention programs. Here, the proposed risk assessment for the injection well is based on a quantitative risk matrix. The proposed assessment for the injection zone is based on methodology used to determine a reservoir probability in exploration and development of oil and gas (*Probability of Success*, abbr. POS), and modified by taking into account hazards that may lead to CO_2 leakage through the cap rock in the atmosphere or groundwater. Such an assessment can eliminate locations that do not meet the basic criteria in regard to short-term and long-term safety and the integrity of the site.

Keywords

geological storage of CO2, preliminary risk assessment, depleted hydrocarbon reservoirs, CO2 leakage, integrity

1. Introduction

The European Union greenhouse gas emission reduction target of at least 40% compared to the 1990 level can be achieved only by applying efficient technologies, which give reliable results in a very short period of time. Carbon Capture and Storage technology (abbr. CCS) considers the removal of CO_2 generated during industrial fuel combustion processes, its transportation and injection into underground storage formations, such as depleted oil and gas reservoirs, coal seams, deep reservoir rocks saturated with salt water and salt domes.

The suitability of geological structures has to be assessed when planning permanent CO_2 disposal. The suitability evaluation includes capacity, injectivity and containment of a geological storage assessment. The assessment takes into consideration the basic criteria for CO_2 storage through the evaluation of certain parameters, such as porosity, permeability, depth of geological structures, seal thickness and impermeability (**Intergovernmental Panel on Climate Change, 2005**; **Loizzo et al., 2010**).

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Carbon dioxide is present with 0.33% in the atmosphere. It is neither flammable nor explosive. Given that in high concentrations it poses a threat to human health and the ecosystem, special attention must be paid to the safety measures applied during the capturing, transportation and storage processes, in order to reduce the existing risk of its leakage to a minimum. The guidelines for risk management through the geological storage lifecycle have been set up within the *EU Directive on the geological storage of carbon dioxide 2009/31/EC* (the so-called *CCS Directive*). The whole technological process of preparation, transportation and injection of CO_2 into the wells is monitored by the relevant procedural and safety equipment, which means that in normal operation and normal production processes, no leakage can occur. Releases from geological storage sites are possible only in the case of incidents.

According to the **Intergovernmental Panel on Climate Change (2005)**, storage durability must resist for at least 1,000 years, meaning that project implementation at a certain location, can be possible only under an acceptable risk level. The first step in the risk assessment process refers to the hazard identification. In a broader sense, a hazard is everything that can cause harm. It considers any source or situation (process condition) which compromises the safety and integrity of underground storage and can cause migration of the injected CO_2 to the surface or to groundwater. All relevant features, events and processes that somehow affect the storage system, must be considered in the evaluation of storage preservation (http://www.quintessa.org/co2fepdb).

As per **Le Guen et al. (2009)** CO_2 leakage may cause: (1) acidification of potable aquifers, (2) acidification of soil, affecting vegetation, (3) accumulation of gaseous CO_2 at the surface, affecting human health and/or the environment, and (4) geomechanical disruption of the underground. The selection of a storage site can be made only if under the proposed usage conditions no significant risk of leakage exists. Storage formation integrity depends on the maintenance of well integrity, as well as sufficient cap and side rocks' sealing capacity.

2. Geological storage components and potential CO_2 migration paths

Potential leakage pathways of injected CO_2 from a storage formation (here, formation means rocks, not a lithostratigraphic unit) towards the surface (into upper rocks, the aquifer or to the atmosphere) could be through a fracture in cap rock, along fault zones and via poorly cemented wells (see **Figure 1**).

2.1. CO_2 injection

Pore-fluid pressurization is the first cause of failure of reservoir, cap rock, and faults. High injection pressure can lead to mechanical failure of the reservoir and/or the cap rock (**Loizzo et al., 2011**). Therefore, depleted oil and gas reservoirs leave a large pore-pressure margin available for repressurization, compared with the narrower margin in saline formations.

It is recommended to carry out CO_2 injection in the supercritical state. Low viscosity of a supercritical fluid allows easy migration through the pore space of the injected layer, but due to the high density peculiar to this phase, its volume is significantly decreased. The supercritical state of CO_2 is defined by pressure above 73.9 bars and temperature over 31.1 ° C. These conditions are almost certainly provided if injecting in layers deeper than 800 m.

2.2. Injection zone

After being injected into hydrocarbon reservoirs or deep layers saturated with salt water, CO_2, as a lighter component, moves up to the shallower parts of the layer, until it encounters impermeable sealing rock (Structural and Stratigraphic Trapping). Due to surface tension and capillary pressure, a part of the CO_2 is retained in the pore space of the injected zone (Residual Trapping).

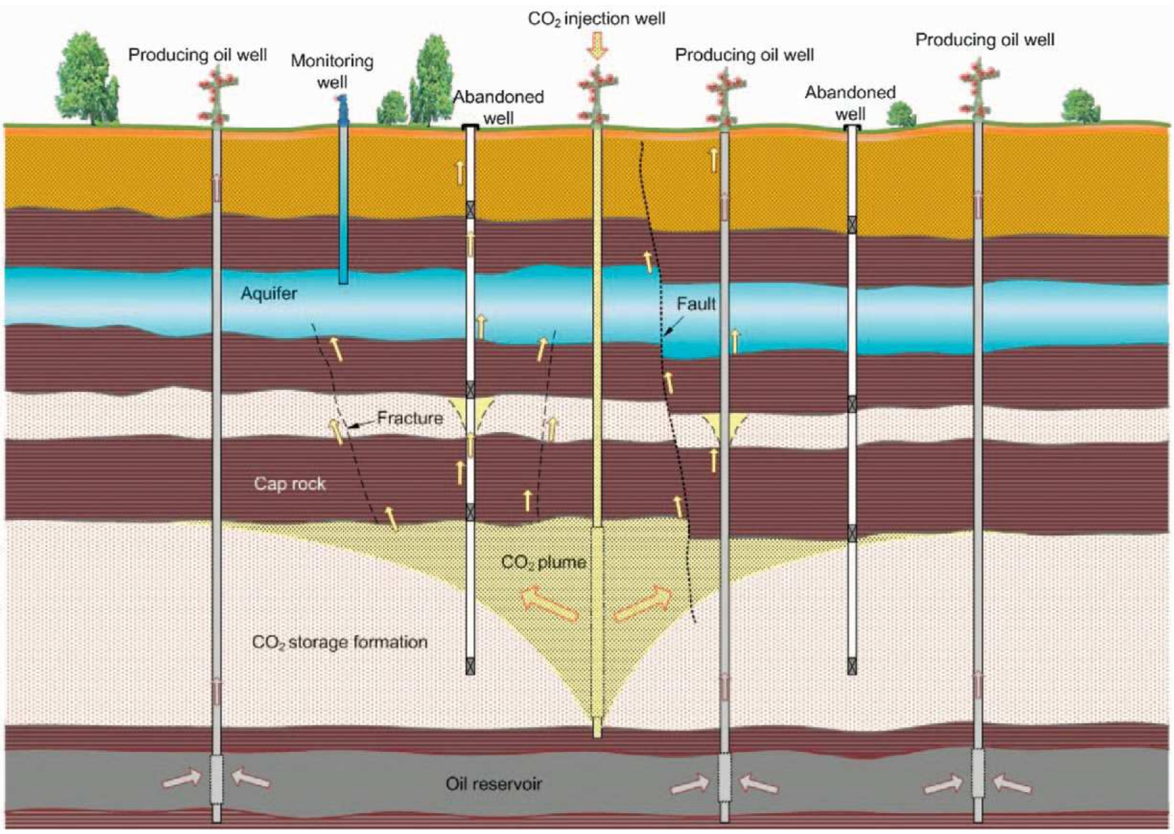

Figure 1: Potential leakage pathways of injected CO_2 (compiled after **Gasda et al., 2004**; **Intergovernmental Panel on Climate Change, 2005**; **Bérard et al., 2007**)

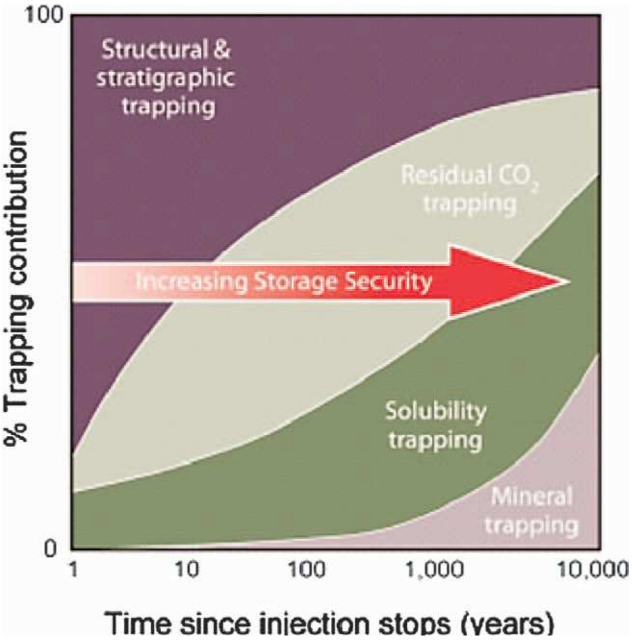

Figure 2: CO_2 trapping mechanisms (**Intergovernmental Panel on Climate Change, 2005**)

Over time, it dissolves in the reservoir fluid and no longer exists as a separate phase (Dissolution Trapping). After thousands years of storage, CO_2 reacts with reservoir rock forming the new stable minerals (Mineral Trapping). It is the most permanent but, at the same time, a very slow mechanism. The share of each CO_2 trapping mechanisms during a geological storage lifetime is shown in **Figure 2** (**Intergovernmental Panel on Climate Change, 2005**; **Imbus et al., 2006**).

The critical elements of the confinement of CO_2 are the caprock overlying the storage formation, and any faults or fractures which occur within the caprock. The structural and stratigraphic trapping mechanisms play a key role when it comes to the migration risk of injected CO_2 from the CO_2 saturated reservoir. The most significant aspect of this mechanism relates to the seal potential of the cap rock, defined by its sealing capacity, geometry and cap rock integrity. Sealing capacity is defined by the height of a CO_2 column that can be held up by the seal rock to the moment when capillary forces in the cap rock pore space are defeated enabling migration due to changes in wettability and/or interfacial tension caused by CO_2 - caprock interaction (**Daniel and Kaldi, 2009**; **Kaldi et al., 2013**).

In cases when CO_2 is stored in depleted hydrocarbon reservoirs, due to the fact that reservoir fluids were held up within geological traps under initial reservoir pressure for 10^5-10^6 years, setting initial reservoir pressure as the final storage value, represents one of the risk reducing measures. However, due to increased capillary inlet pressure of CO_2 compared to CH_4, a rock, which represents a barrier regarding CH_4 migration, does not have to be in the same function when it comes to CO_2. When increasing supercritical CO_2 pressure, the difference between CO_2 pressure in reservoir rock at the point of contact with the cap rock and cap rock pore water pressure may increase above the capillary pressure value allowing penetration of non-wettable CO_2 into the cap rock and the creation of the slow flow of CO_2 through the seal (**Hildenbrand et al., 2002**; **Li et al. 2005**). Furthermore, the mineralogical changes in the seal caused by geochemical reactions among rock, reservoir fluid and CO_2 can result in the dissolution or precipitation of minerals and thus lead to permeability changes (**Daniel and Kaldi, 2009**; **Kald et al., 2013**; **Husanović et al., 2015**).

Novak (2015) uses the *Possibility of Success* (abbr. POS) methodology in determining the possibility of retention of CO_2 in the reservoir system and shows that the methodology can be successfully used not only for the assessment of new hydrocarbon discovery in petroleum systems, but also in all qualitative assessments of such systems.

Cap rock integrity is determined by the role of fault and smaller fracture systems that could control CO_2 migration. In some cases, faults and fractures, if cemented, are sealing barriers that hold oil and gas for millions of years, while in other cases they are fluid migration pathways to the shallower layers. The role of faults and fractures in controlling the migration of CO_2 is estimated by studying regional geology, field subsurface maps, hydrology and geochemistry reservoir conditions. However, when comparing CO_2 leakage potential, fracture or fault-related leakage possibility is more likely than leak possibility through the seal (**Jimenez and Chalaturnyk, 2002**).

2.3. CO_2 injection well

The injection of CO_2 underground is carried out through the injection well. For CO_2 injection, new wells can be made or existing ones used. Wellbore penetrates the CO_2 storage formation and can become a potential pathway for the migration of CO_2 out of the injection zone into the aquifer up to the surface. Another potential path is through the cap rock and faults. In other words, wellbore integrity is one of the key performance criteria in the geological storage of CO_2. It demonstrates that the wellbore is a long-term safe barrier for CO_2 confinement and is of superior importance for a CO_2 injection projects' acceptance and deployment.

New CO_2 injection wells must be drilled using safety factors that enable operators to isolate storage formation from leakage pathways. They have to be cased and cemented to prevent the migration of CO_2 into or between underground sources of drinking water. The casing and cement should be designed for the life expectancy of the well, and well completion must be performed using corrosion-resistant materials. **National Energy Technology Laboratory (2009)** published mandatory technical requirements for CO_2 injection well (Class VI).

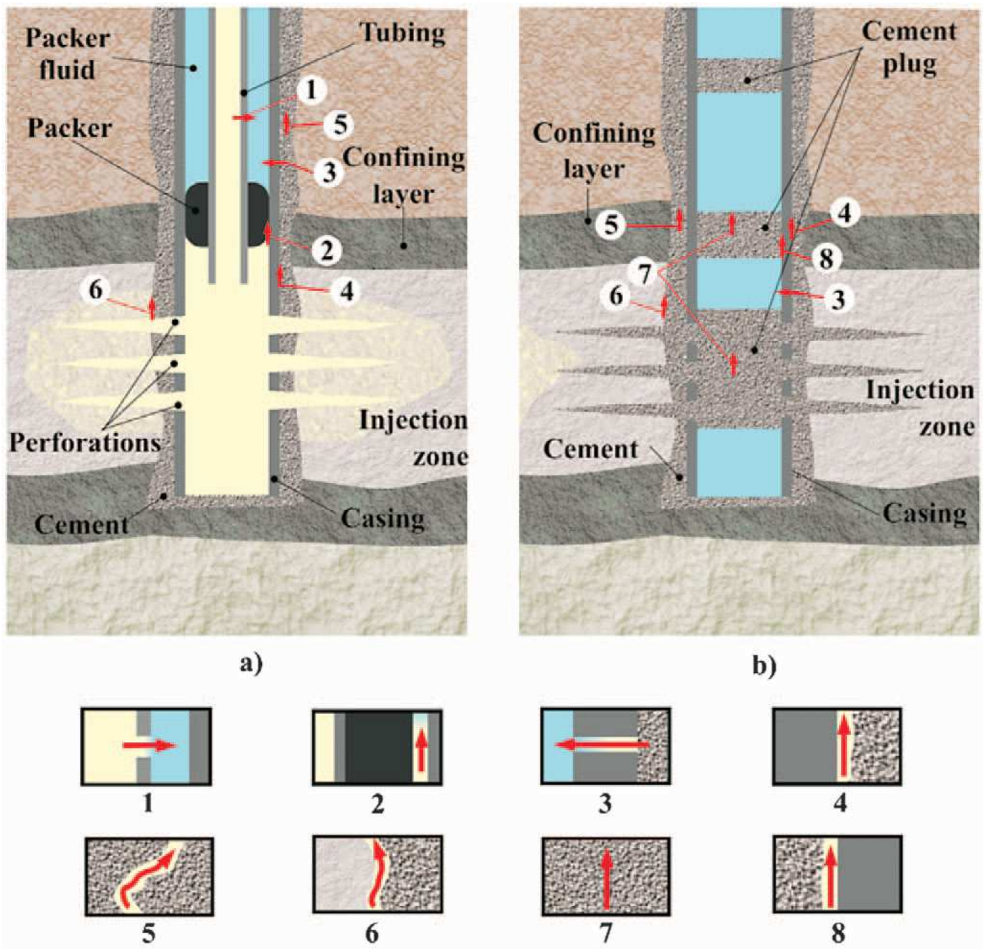

Figure 3: Possible leakage pathways in an active CO_2 well (a) and an abandoned well (b) (**Gaurina-Međimurec and Pašić, 2011**)

Existing wells (active, inactive or abandoned) can be or can become potential pathways for leakage. This needs to be particularly considered when using hydrocarbon fields for CO_2 storage. The age of the wells has an inverse relation to the well integrity. With age, the casing/tubing strength and the cement behind casings will start deteriorating due to the factors like corrosion, thermal changes, fatigue due to production or injection, etc. (**Amrideswaran et al., 2015**). Therefore, special attention should be paid to assessing the integrity of the existing wells, which are intended to be used for CO_2 injection.

Several potential leakage pathways can occur along active injection wells (see **Figure 3a**) and/or abandoned wells (see **Figure 3b**). These include leakage: through deterioration (corrosion) of the tubing (1), around the packer (2), through deterioration (corrosion) of the casing (3), between the outside of the casing and the cement (4), through deterioration of the cement in the annulus (cement fractures) (5), leakage in the annular region between the cement and the formations (6), through the cement plug (7), and between the cement and the inside of the casing (8) (**Gaurina-Međimurec and Pašić, 2011**).

The term "well integrity" includes internal mechanical integrity (the absence of significant leaks in the casing, tubing, or packer) and the external one (the absence of significant leakage outside of casing). It is of major importance to prove the reliability and safety of long-term CO_2 geological storage and this represents a key issue for the assessment of impact on the environment and public acceptance. Except terms "internal" and "external" mechanical integrity, according to the *NORSK standard D-010*, the terms "primary barrier" (tubing, packer and safety valve) and "secondary barrier" (the cement outside the casing, the casing itself and the wellhead valves) can be used.

The migration of CO_2 around the packer, through the tubing or through the casing is prevented by maintaining the internal integrity. The internal integrity is achieved by selecting suitable materials for each individual piece of equipment. In the CO_2 injection wells, there is the possibility of corrosion of: (1) equipment parts that come into contact with CO_2, (2) the tubing and (3) the part of the casing string below the packer. Therefore, to avoid the corrosion of tubing and casing, they should be made of corrosion-resistant materials, i.e. 316 stainless steel (SS), glass reinforced epoxy (GRE) or lined carbon steel. Packers and valves can be nickel-plated or made of other high nickel alloys (**Gaurina-Međimurec, 2010**;

Table 1: An example of a qualitative risk matrix (**Gaurina-Međimurec et al., 2015**)

CONSEQUENCE		LIKELIHOOD				
		Rare E	Unlikely D	Possible C	Likely B	Almost Certain A
Severe	5	M	H	H	E	E
Major	4	M	M	H	H	E
Moderate	3	L	M	H	H	H
Minor	2	L	L	M	M	H
Negligibe	1	L	L	M	M	H
Risk rating: E - Extreme, H - High, M - Moderate, L - Low						

Gaurina-Međimurec and Pašić, 2011). If carbon steel is used, it is necessary to inject a corrosion inhibitor.

The migration of the injected CO_2 upwards from the injection zone is prevented by maintaining the external integrity. The external integrity is achieved by set cement. Properly cemented casing should protect the casing string from stress and corrosion, as well as prevent CO_2 migration by sealing the annulus (**Gaurina-Međimurec, 2010**; **Gaurina-Međimurec and Pašić, 2011**). Portland cement is conventionally used for cementing in oil and gas wells. The cement sheath seals the annulus between the casing (a pipe which is inserted to stabilise the borehole of a well after it is drilled) and the borehole walls, and prevents the migration of fluid between the formation (the body of rock of considerable extent with distinctive characteristics that allow geologists to map, describe and name its rocks) and the casing. Cement is also used to plug the casing in case of well abandonment. Portland cement is thermodynamically unstable in CO_2-rich environments. Injected CO_2 in the presence of water forms carbonic acid (H_2CO_3). This chemical reaction, over time, leads to the degradation of Portland cement in terms of reducing the compressive strength and increasing the porosity and permeability of set cement. The reason is the migration of soluble gel, calcium silicate hydrate from the cement matrix. To prevent set cement degradation, the use of CO_2 resistant Portland cement or cement with a greater proportion of pozzolan is recommended (**Onan, 1984**; **Kutchko et al., 2007**; **Bellarby, 2009**; **Santra et al., 2009**; **Gaurina-Međimurec, 2010**; **Gaurina-Međimurec and Pašić, 2011**). In addition to that, modelling of well cement degradation due to the presence of CO_2 needs to be performed at low, acidic pH values.

3. Risk Assessment

Risk assessment is used to ensure the safety and acceptability of the geological storage of CO_2. It involves determining both the consequences and likelihood of an event. It can be defined as the combination of the likelihood of a failure event, i.e. its probability and the magnitude of its impact, i.e. its severity (**Le Guen et al., 2008** and **2009**; **Gaurina-Međimurec et al., 2015**). There are simple and complex risk assessment matrixes but all present categories of the likelihood that a particular event will occur (incident occurrence probability) and the severity of consequences (the magnitude of harm or damage that could happen). Risk assessment can be performed by using qualitative or quantitative methods.

Qualitative risk assessment methods use descriptive terms to define the likelihoods, i.e. probabilities, and consequences of risk events, and the resultant risk is the product of consequence and likelihood. Qualitative approaches to risk assessment are most commonly applied and allow us to transform risk events into risk ratings. Also such an approach allows us to easily (a) apply the method in other hydrocarbon provinces anywhere, (b) reduce or increase the number of probability events depending on the needs and the available data. Outputs from qualitative risk analyses are usually evaluated using a risk matrix format. **Table 1** shows an example of a qualitative risk matrix.

Risk should be ranked so that priorities can be established. Each risk is categorized in accordance with the terms shown in **Table 1** such as: Extreme (E), High (H), Moderate (M), and Low (L). Generally, remedial actions or acceptance of risk for different risk categories are:

- Extreme risk (E): operation not permissible,
- High risk (H): remedial action to have high priority,
- Moderate risk (M): remedial action to be taken at the appropriate time,
- Low (L): risk is acceptable; remedial action is discretionary.

Quantitative risk assessment methods identify the likelihood of a failure event as frequencies or probabilities, and consequences in terms of relative scale (orders of magnitude of a failure event) or in terms of specific values (e.g., CO_2 leakage mass, estimates of cost, personal injury, environment damage, etc.). The resultant risk is the product of probability (likelihood of a failure event) and severity (the magnitude of failure event impact).

In the case of well integrity, the failure event (that can occur in the present and/or in the future) is represented by conditions that could lead to a leak for which a probability of occurrence is proposed. Consequences of impact of a leakage could be assessed with respect to all the stakes involved in a CO_2 storage project. Events with higher severity (more significant consequences) and probability are identified as higher risk, and are selected for higher priority mitigation actions in order to decrease the probability of the event occurring and/or reduce the consequences if the event was to occur.

Preliminary risk assessment described in this paper is aimed at: (1) identifying risks of CO_2 leakage from the injection zone and through wells, (2) quantifying risk in terms of probability and severity, in order to establish a prevention program and a risk-mitigation plan.

3.1. Risk assessment for the injection zone

The appearance of risk of some event within the oil and gas system can be considered as an equivalent to the statistics *Probability of Success* (POS) concept. This means that for the evaluation of CO_2 retention possibility, an analogy with the methodology for assessment of CH_4 migration can be used. Here, the proposed preliminary hazard analysis and risk assessment methodology for the migration of CO_2 from geological storage is based on **White's (1993)** methodology, used to determine the probability of hydrocarbon reservoir discovery prior to drilling at a selected location, later modified by **Malvić (2003)**, and **Malvić and Rusan (2009)** in order to be valid for the whole area of the Croatian part of the Pannonian Basin System.

Table 2: Geological events classification in POS calculation of hydrocarbon system

1.00	Almost certain event (in the original Proven)
0.75	Very likely event (in the original Highly reliable prediction)
0.50	Likely event (in the original Fairly reliable prediction)
0.25	Unlikely event (in the original Unreliable prediction)
0.05	Impossible/Rare event (Missing/Undefined parameter)

Unlike the *POS* methodology described in the above mentioned works, the methodology suggested in this paper uses only two geological categories (a) *the Trap* and (b) *the Reservoir*, but for this purpose, they are additionally modified in line with criteria important for preserving geological storage integrity. The mentioned categories are divided into sub-categories which are further described by a series of events. The probability of each category is determined by selecting a proper event corresponding to the given storage system in each of the sub-category, and by multiplying the associated probability values, which are in the range of 0.05 -1.00. Some categories cannot be reliably estimated due to insufficient data. Whenever regional analogy indicates only potential, but completely unproven, storage or other variable, elimination of such sites due to multiplication with 0 can be prevented by assigning a probability value of 0.05 to the assumed impossible events. The obtained value is classified into one of five probability classes: an Almost certain event (1.0), a Very likely event (0.75), a Likely event (0.5), an Unlikely event (0.25) and an Impossible/Rare event (0.05) as shown in **Table 2** (**Malvić**, **2003**; **Malvić and Rusan, 2009**; **Novak, 2015**).

The Trap category is defined as a confined geological structure, defined by subcategories and probabilities, as shown in **Table 3**. The total probability of the category (p) is calculated multiplying probabilities of its subcategories (see **Equation 1**):

$$\begin{aligned} &p\ (\text{Trap}) = \\ &= [p\ (\text{Structural trap})\ \text{or}\ p\ (\text{Stratigraphic trap})] \cdot \\ &\cdot\ p\ (\text{Quality and thickness of cap rock}) \end{aligned} \tag{1}$$

Where:

p (Trap) – probability of the Trap category

p (Structural trap) – probability of the Structural trap sub-category,

p (Stratigraphic trap) – probability of the Stratigraphic trap sub-category,

p (Quality and thickness of cap rock) – probability of the Quality and thickness of cap rock sub-category.

Table 3: The Trap category with its subcategories and geological events classified in five probability classes (modified according to **Malvić and Rusan, 2009**)

Trap	Structural trap	Stratigraphic and combined trap	Quality and thickness of cap rock
1.0	Anticline and buried hill	Algae reef form	Regionally proven cap rock (seal, isolator) > 100 m
0.75	Faulted anticline	Sandstone, pinched out	Regionally proven cap rock (seal, isolator) 30 - 100 m
0.50	Structural nose closed by fault	Sediments changed by diagenesis	Proven cap rock < 30 m
0.25	Any positive faulted structure, margins are not firmly defined	Petrophysical properties changes (clay, different facies)	Proven cap rock 10 - 30 m
0.05	Undefined structure	Undefined stratigraphy	Gas permeable rock Permeable rock with locally higher silt/clay content Undefined cap rock

Table 4: The Reservoir category with its subcategories and events classified in five probability classes (modified according to **Malvić and Rusan, 2009**)

Reservoir	Reservoir type	Porosity features	Reservoir pressure
1.0	Sandstone, clean and laterally extending. Basement: granite, gneiss, gabbro; Dolomite and algae reefs	Primary porosity >15 %; Secondary porosity >5 %	Reservoir pressure > 80 bar
0.75	Sandstones rich in silt and clays. Basement rock with secondary porosity, limited extending. Algae reefs filled with skeletal debris, mud and marine cements.	Primary porosity 5 - 15 %; Secondary porosity 1 - 5 %	Reservoir pressure < 80 bar
0.50	Sandstone with significant particles of silt/clay, limited extending	Primary porosity < 10 %; Permeability < $1 \cdot 10^{-3}$ µm^2	-
0.25	Basement rock, including low secondary porosity and limited extending	Secondary porosity < 1 %	-
0.05	Undefined reservoir type	Undefined porosity	-

Table 5: The Reservoir category with its subcategories and events classified in five probability classes

Probability of success for CO_2 injection in subsurface volumen		Probability of trap				
		1.0	0.75	0.50	0.25	0.05
Probability of favourable lithofacies	1.00	CE	VLE	LE	ULE	RE
	0.75	VLE	LE	ULE	RE	IE
	0.50	LE	U	ULE	RE	IE
	0.25	ULE	RE	RE	RE	IE
	0.05	RE	IE	IE	IE	IE
CE - Certain event (1.00), VLE - Very likely event (0.75– 0.99), LE - Likely event (0.50 – 0.74), ULE - Unlikely event (0.25 – 0.49), RE - Rare event (0.05 – 0.24), IE - Impossible event (< 0.005)						

The Reservoir category is considered through the reservoir rock type, porosity value and reservoir pressure, as shown in **Table 4.** Multiplication of these subcategories determines the probability of reservoir existence and its type, suitability for CO_2 injection (see **Equation 2**):

$$p\ (\text{Reservoir}) = p\ (\text{Reservoir type}) \cdot \cdot\ p\ (\text{Porosity features}) \cdot p\ (\text{Reservoir pressure}) \quad (2)$$

Where:

p (Reservoir) – probability of the Reservoir category

p (Reservoir type) – probability of the Reservoir type sub-category,

p (Porosity features) – probability of the Porosity features sub-category,

p (Reservoir pressure) – probability of the Reservoir pressure sub-category.

Multiplication of these categories finally results in Probability of Success (see **Equation 3**):

$$POS = p\ (\mathit{Trap}) \cdot p\ (\mathit{Reservoir}) \quad (3)$$

Where:

POS – Probability of Success,

p (Trap) – probability of the Trap category,

p (Reservoir) – probability of the Reservoir category.

Obtained values fall into one of the categories representing: a Certain event (1.00), a Very likely event (0.75– 0.99), a Likely event (0.50 – 0.74), an Unlikely event (0.25 – 0.49), a Rare event (0.05 – 0.24) and an Impossible event (< 0.005) as shown in **Table 5.** If the estimated probability falls in the range from 0.5 to 1.0, the reservoir is of high enough quality (extension, thickness, porosity, permeability) that the site can be evaluated as the location of low to moderate risk of migration of the injected CO_2, and can be proposed for further consideration. The cross-connection of two geological categories here selected as crucial for outlining subsurface volumes suitable for CO_2 injection in depleted hydrocarbon reservoirs is summarised in **Table 5**.

3.2. Risk assessment for a CO_2 injection well

Long-term well integrity performance assessment is one of the critical steps that must be addressed before CO_2 injection. This is so because wells are often considered to be the weakest spots with respect to the safety of CO_2 confinement in the storage formation (saline aquifers, depleted reservoir, coal seams, etc.). Well integrity assessment describes the capabilities of a well to contain CO_2 (i.e. to confine the injected gas within the storage formation), or at least make sure it does not reach a shallow formation (i.e. freshwater aquifers seepage) or surface (leakage) (**Meyer et al., 2009**). Because of uncertainties associated with the possibility for CO_2 to leak along the wellbore and its related impacts, it is very important to be able to demonstrate that the wellbore constitutes a safe long-term seal, and to use simulation tools for leakage quantification.

Before starting any well integrity risk analysis, the system must be defined, and its processes must be described including the physical environment of the well, which elements can interact with the well components (i.e., the cap rock and specific formations located above the CO_2 storage formation, subsurface fluids, shallow subsurface or soil, surface, atmosphere).

Well integrity risk analysis usually starts with the definition of its scope and consists of three components: (1) failure (hazardous) event, (2) endangered targets, and (3) duration of the risk analysis interval. In the case of a CO_2 injection well, a hazardous event refers to the failure of tubing, packer, casing or cement that can cause damage to a target. Targets are the elements (i.e., freshwater aquifer, soil, air, and environment) that may be affected by the loss of mechanical integrity of wells with the result of CO_2 leakage. The duration of the risk analysis interval used to compute CO_2 leakage risk can be up to 1,000 years.

Many authors use quantitative risk-based methodology to evaluate the performance and risks (P&R) associated with well integrity in order to prevent leakage of the injected CO_2 (**Berard et al., 2007**; **Le Guen et al., 2008** and **2009**; **Houdu et al, 2008**; **Meyer et al., 2009**; **D'Alesio et al., 2011**; **Loizzo et al., 2015**). Quantification of the capacity for injected CO_2 to migrate through a well system requires the use of mathematical models and numerical tools.

Well integrity assessment workflow usually comprises several important elements and main steps: (a) collecting and interpreting all available well data (e.g., cement logs, drilling reports, geological interpretations), (b) creating a static model of the well including its geometrical and integrity parameters and wellbore geology nearby, (c) creating a dynamic model taking into account the static model of the well and possible processes in the borehole during CO_2 injection (e.g., cement degradation, casing corrosion, CO_2 migration, initial and limit conditions), (d) calculation of CO_2 leakage mass during time and probability (frequency grid; a table of frequencies and corresponding probabilities), (e) assessing severity (consequences grid; a table of severities and corresponding consequences), (f) risk mapping and risk distribution plotting. At the end of the process, recommendations and risk-reducing measures based on risk assessment should be made (**Van Der Beken et al., 2007**; **Meyer et al., 2009**; **Le Guen et al., 2009**). They usually include: inspection, design, operational, and monitoring recommendations and/or mitigation options adapted to the identified risk sources. **Figure 4** shows a typical flow chart for risk assessment of the CO_2 injection well integrity.

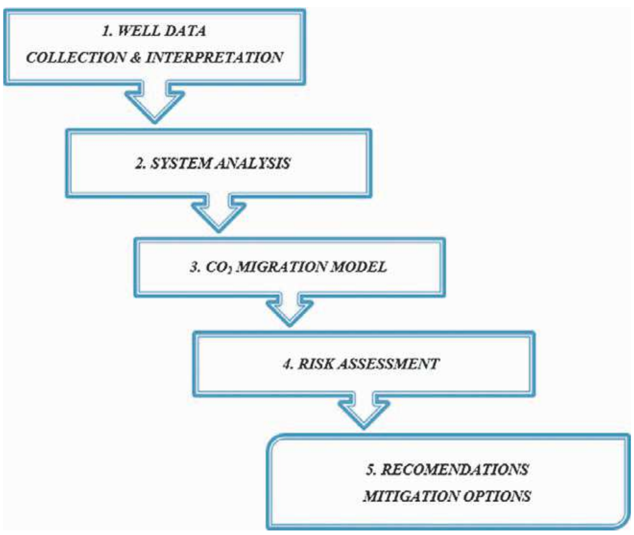

Figure 4: Well integrity risk assessment flow chart

3.2.1. Risk sources of CO_2 leakage

Risk sources of CO_2 leakage from the injection zone and through wells can be (**Le Guen et al., 2009**; **Meyer et al., 2009**): (1) well-component characteristics (i.e., tubulars, cement zones), (2) uncertainties associated with the geometrical, physical, and mechanical properties, and (3) degradation mechanisms (e.g., cement leaching/carbonation by acid fluid, CO_2 corrosion of tubing and casing, etc.).

Le Guen et al. (2009) use functional analysis to identify the component characteristics that contribute to the highest criticality scenario. The functional analysis takes into consideration: well components and their functions, failure modes of well components, as well as causes and effects of each failure mode. Function of tubulars are: (1) to resist formation fluids pressure, (2) to ensure sealing with respect to formation fluids, (3) to resist CO_2 pressure and temperature, (4) to ensure sealing with respect to injected CO_2, and (5) to resist formation pressure (creep).

Various causes of tubular and cement failure such as: corrosion, erosion, and shrinkage due to temperature variations, can lead to the following consequences: loss in mechanical resistance, loss in sealing with respect to the formation fluids or to the CO_2, and overpressure.

3.2.2. Quantification of the risk of CO_2 leakage

Quantitative methods identify likelihoods as frequencies or probabilities, and consequences in terms of relative scale (orders of magnitude) or in terms of specific values (e.g, estimates of cost, CO_2 leakage mass, sustained casing pressure – *SCP*, etc.). The uncertainties of the system are converted into terms of probability (see **Table 6**).

The quantitative CO_2 leakage mass assessed are converted into the term of severity (see **Table 7**). Leakage rates are estimated to be very small for geological formations chosen with care. Some of the injected CO_2 could be released to the atmosphere over a period of hundreds to thousands of years, depending on the depth and location of injection.

Table 6: An example of a frequency grid and probability of CO_2 leakage

Frequency grid			
Le Guen et al., 2009		Loizzo et al., 2015	
Frequency Level	Probability	Frequency Level (Class)	Probability (Events per well per year)
1	≤ 0.00001	A	≤ 6 x 10^{-5}
2	≤ 0.0001	B	≤ 2 x 10^{-4}
3	≤ 0.001	C	≤ 6 x 10^{-4}
4	≤ 0.01	D	≤ 6 x 10^{-3}
5	≤ 0.1	E	> 2 x 10^{-3}
6	≤ 1.0		

Table 7: An example of a consequence grid and severity levels of leakage of injected fluids

Consequence grid			
Guen et al., 2009		Loizzo et al., 2015	
Severity Level	Consequence (Loss of injected CO_2 over 1000 years, %)	Severity Level (Class)	Consequence (Total hazardous-fluid leak volume, m^3)
Minor	≤ 0.05	Minor	< 2
Low	0.06 – 0.10	Serious	2 - 29
Serious	0.11 – 0.25	Major	30 - 99
Major	0.26 – 0.50	Catastrophic	≥ 100
Critical	0.51 – 1.00	-	-
Extreme	> 1	-	-

Physical leakage or emission of CO_2 from storage could be defined as follows (**Intergovernmental Panel on Climate Change, 2005**) (see **Equation 4**):

$$\text{Emissions of } CO_2 \text{ from storage} = \int_O^T m(t)dt \qquad (4)$$

Where:

m(t) – the mass of CO_2 emitted to the atmosphere per unit of time,

T – the assessment time period.

For monitoring of possible leakage of CO_2 from geological formations, direct measurement methods for CO_2 detection, geochemical methods and tracers, or indirect measurement methods for CO_2 plume detection can be used.

Many authors use a “scenario” approach to determine uncertain parameters (**Van Der Beken et al. 2007**; **Le Guen et al., 2009**; **Meyer et al, 2009**; **Nabih and Chalaturnyk, 2013** and **2013 a**). A scenario represents possible well integrity conditions whose parameters give a value within the defined range. Each scenario is a combination of a specific set of parameters describing the static and dynamic models within the range of uncertainties. CO_2 leakage simulations should be performed for every scenario over the given time period. The result of each simulation is a CO_2 leakage mass in any target of interest (shallow aquifers or surface). The amount of CO_2 leakage in shallow aquifers or to the surface is used for risk quantification and risk mapping.

Table 8 presents an example of risk matrix dedicated to well integrity in terms of loss of injected CO_2 over 1,000 years. The thick black line in **Table 8** presents the Risk Acceptance Limit.

4. Discussion

Depleted oil and gas reservoirs are one of the most perspective options for carbon sequestration, due to significant storage capacity, existing infrastructure that economically justify the implementation of such projects, but also due to the acceptable risk of CO_2 migration thanks to reservoir capability to retain fluid.

Commercial application of the *CCS* technology is still not possible due to a low CO_2 price at the *EU ETS* market. In order to meet the greenhouse gas emission reductions required by the European Commission, the price will necessary go up, encouraging investments in the projects of safe and effective technology for permanent CO_2 removal from the atmosphere. According to the *EU Directive on the geological storage of carbon dioxide in 2009/31/EC*, the geological storage of CO_2 performed

Table 8: An example of risk matrix dedicated to CO_2 well integrity

Risk=Probability x Severity			Frequency level					
			1	2	3	4	5	6
			Probability					
Severity levels		Loss of injected CO_2 over 1000 years (%)	≤10^{-5}	≤10^{-4}	≤10^{-3}	≤10^{-2}	≤10^{-1}	≤10^{0}
1	Minor	≤0,05						
2	Low	0.06 – 0.10						
3	Serious	0.11 – 0.25						
4	Major	0.26 – 0.50						
5	Critical	0.51 – 1.00						
6	Extreme	>1.00						

in a safe way considers maximal elimination of risks for the environment and human health. The Directive is transposed into national regulation through the *Mining Act "Official Gazette" no. 56/13 and 14/14* and the *Ordinance on permanent disposal of gases in geological structures "Official Gazette" no. 106/13*.

Being a direct connection to the surface, the wells represent the most common route for migration. However, when CO_2 enters underground, the hazards shift from the sphere of humanly controlled conditions to the natural system, which increases the degree of uncertainty. The behaviour of injected CO_2 is influenced by different parameters, such as geometry of reservoir and cap rocks, stratigraphic relations, reservoir heterogeneity, relative permeability, faults and fractures, pressure and temperature conditions, mineralogical composition, hydrodynamic conditions, reservoir fluids chemistry, etc. (**Root, 2007**; **Kaldi et al., 2013**).

The methodology for the preliminary assessment of migration risk of CO_2 stored underground proposed in this paper is suggested in order to eliminate sites that do not meet the basic criteria in ensuring geological storage sustainability. It is about a simple and user friendly tool. Since it includes all the geological storage components necessary for integrity preservation, the proposed methodology can be usefully applied when selecting the location of potential storage, suitable for further consideration. However, due to the geological complexity and diversity of each reservoir, further modelling is needed in order to understand storage complex behaviour.

Characterization and assessment of a storage complex through static and dynamic modelling requires the involvement of a multidisciplinary research team. The three-dimensional static model of geological storage is defined by a structural model (distribution of reservoir volume), petrophysical model (distribution of porosity, permeability, and fluid saturation), fluid contacts, and calculated volume available for injection. Dynamic modelling includes a series of simulations of CO_2 injection into the reservoir in different time intervals by applying the three-dimensional static model. It is used in order to predict: the behaviour of injected CO_2 through the pore space, displacement of water or hydrocarbons with CO_2, reservoir pressure increase, geochemical reactions among CO_2, reservoir fluid, and rock minerals, deformation of reservoir and cap rock by increasing formation pressure, changes in the state of stress in fractures and faults affecting sealing characteristics, induced seismicity, potential migration through inappropriately abandoned wells, etc.

Although there is no common definition of risk agreed on by all authors, most often it is defined as the chance of damage, or loss; the degree of probability of loss, the amount of possible loss. Any risk analysis must include possible hazards and targets. It must rely on an observed system definition and description of the physical environment (i.e., specific formations located above the CO_2 reservoir and the cap rock, soil, surface, atmosphere, etc.) (**Le Guen, 2009**). Although for all CO_2 storage sites, appropriate hazard characterization and effective management can identify a certain number of hazards, many of them can be reduced to an acceptable level (**Intergovernmental Panel on Climate Change, 2005**). The risk assessment has to define a leakage potential of injected CO_2 through wells, faults, fractures and seismic events (**Forbes et al., 2008**). It must investigate fluid potential impacts on storage integrity, human health and the environment providing the basis for response plans and monitoring strategies for a given site (**Međimurec and Pašić, 2011**)

Abandoned or active wells that penetrate the storage formation pose the greatest risk for CO_2 leakage. However, in both cases, it is necessary to ensure long-term well integrity. According to research on 419 wells in Qatar Petroleum's Dukhan onshore oil field, the age of the wells is inversely proportional to well integrity. Corrosion, thermal changes, fatigues due to injection and some other factors can cause casing/tubing strength and cement deterioration. Therefore, special attention has to be paid to the well integrity assessment (**Amrideswaran et al., 2015**).

The risk can be simply defined as the product of the probability of the occurrence of a failure event (likelihood) and severity of its consequences (expected loss). Risk matrix is the most commonly applied tool in risk assessment, used to determine risk significance through the description of consequence severity and likelihood of an unwanted event. A different perspective can be used to define severity, but usually it is considered from the aspect of People, Environment, Assets and Reputation (*PEAR*). By a combination of probability and severity, each event is ranked into one of the risk categories ranging from the *Very Low* to the *Extreme*. Whenever more significant consequences and likelihoods are identified, such events are selected for higher priority mitigation actions applied for decreasing the likelihood of their occurrence and/or reducing the consequences.

5. Conclusion

Since the term of "risk" of an event within the oil and gas system can be considered as the equivalent to the concept of probability of reservoir discovery, to assess the likelihood of injected CO_2 retention within the reservoir, the *POS* methodology (**White, 1993**; **Malvić, 2003**; **Malvić and Rusan 2009**; **Novak 2015**) further modified according to the criteria important in terms of storage complex efficiency and preservation (conditions that ensure a supercritical state, internal and external mechanical well integrity, reservoir pressure, etc.) is suggested. The methodology uses geological categories the *Trap*, and the *Reservoir*, divided into the series of sub-categories and related events to estimate the risk of migration of the injected CO_2 from depleted hydrocarbon reservoirs. Multiplying corresponding probability values leads to the definition of category probability. This value can be classified into one of five probability classes: a Certain event (1.0), a Very likely event (0.75), a Probable event (0.5), an Unlikely event (0.25) and an Impossible/Rare event (0.05). A storage complex for which the estimated probability falls in the range from 0.5 to 1.0 is evaluated as the location posing low to moderate risk of migration of the injected CO_2, and therefore is proposed for further consideration.

Features of CO_2 storage sites with a low probability of leakage include highly impermeable cap rocks, geological stability, the absence of leakage paths and effective trapping mechanisms. Unfortunately, every CO_2 storage project includes some risk of unwanted migration of injected CO_2 from the storage reservoir and thus requires a comprehensive risk assessment. For this purpose, a large number of CO_2 injection scenarios have to be assessed using different well configurations and testing uncertainties in the static and dynamic models, including possible worst-case scenarios. Potential risks include short and long-term releases of CO_2 to the aquifer, surface, lateral migration to adjacent fields and wellbores, and lateral migration of dissolved CO_2. A comprehensive risk assessment has to be carried out, linking threats to consequences via a range of preventative and remediation measures. Leakage scenarios have to be assessed, prioritizing various possibilities for wellbore leakage, but also addressing leakage via the geological pathways. Once leakages are detected, some remediation techniques are available to stop or control them. The remediation measures plan must be based on the risk assessment and focus on addressing significant irregularities, with the ultimate aim of preventing or repairing leakage or emissions of CO_2. The remediation measures have to be designed ranging from additional contingency monitoring, through the adaptation of the injection program, to wellbore interventions, and if necessary, a full well kill by the drilling of a new relief well. In the case of low risk, remedial action is discretionary, at moderate risk, remedial action has to be taken at the appropriate time, but in the case of high risk, remedial action has high priority. In a situation of extreme risk, the operation of CO_2 injection is not permissible.

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